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Assessing operating regimes of CCS power plants in high wind and energy storage scenarios

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Abstract

This paper investigates the operating regimes of CCS power plants in future generation portfolios with large amounts of variable-output wind generation. An advanced electricity system dispatch model is developed and coupled with a Monte Carlo based energy storage optimization model to simulate the least-cost dispatch of an assumed thermal-energy storage generation portfolio with CCS. A historic high-resolution wind speed reanalysis dataset is employed and the proposed locations of future wind farms are used to produce plausible and internally consistent wind capacity deployment scenarios. The fundamental and structural changes that occur to CCS operating profiles and start-up/shut-down schedules are investigated for increasing levels of wind capacity, which creates seasonal and diurnal variations and potential flexibility implications. Non-linear interactions between flexible CCS power plants and other energy vectors are demonstrated for an illustrative case study example in Great Britain. This temporally explicit analysis of the short-term scheduling decisions of thermal plants with CCS highlights the asymmetric displacement of mid-merit thermal plants and the importance of using time-dependent start-up costs in wind-based unit commitment studies.

Peer-review under responsibility of the Organizing Committee of GHGT-12

Keywords: carbon capture and storage; flexibility; wind; variability; energy storage; unit commitment; dispatch

1. Introduction and scope

To reduce electricity sector carbon dioxide (CO_2) emissions, the large-scale deployment of low-carbon generation technologies, such as weather-variable renewable energy sources (VRE) and CO_2 capture and storage (CCS) will be necessary [1]. This will, however, create fundamental and structural changes to electricity systems. Price insensitive

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VRE, such as wind, have near zero variable operating costs and, hence, typically priority of dispatch. They, therefore, displace thermal power plants with higher variable operating costs. This tends to lead to interrupted operating patterns and decreased load factors for thermal power plants. In addition, increasing proportions of non-controllable and partially unpredictable VRE relative to dispatchable generation, will create operational flexibility issues for power systems. The residual thermal generation fleet will increasingly have to respond to weather variation and forecasting errors associated with VRE power generation. It is therefore important to consider what operating patterns may be needed from future low-carbon dispatchable generation to respond to short-term fluctuations in residual demand (i.e. the demand for electricity after VRE and energy storage is dispatched).

Recent work has investigated the flexibility of power plants with CCS [2,3,4,5,6]. However, these studies do not consider the operability or flexibility of CCS power plants as part of a full electricity system with large contributions from wind power and energy storage. It is not well understood how increasing amounts of VRE will affect power price shape, dispatch patterns, and start-up/shut-down schedules of thermal power plants, or the operation of energy storage units. Increased residual demand variability is generally expected to increase price differentials and volatility, expanding the arbitrage opportunities for energy storage [7]. In addition, it is likely that certain power systems may have large proportions of nuclear capacity, which may be designed and/or financed to operate inflexibly. Nuclear may therefore only be able to provide limited flexibility, either because of technical constraints or commercial interests, increasing the flexibility requirements of residual power plants.

These effects will impact the start-up/shut-down requirements and dispatch of the residual thermal power plant fleet. It is therefore important to explore whether CCS-enabled power plants are able to provide price-sensitive flexible generation to provide infill generation to complement low variable operating cost generation (i.e. many VRE generators and nuclear power plants). There is, however, limited understanding of the likely operating patterns of these plants. The objective of this paper is, therefore, to highlight the changes that are likely to occur to thermal plant operating regimes in future generation portfolios with CCS, and illustrate potential interactions that might occur between CCS, wind (as an illustrative VRE), and energy storage assets. This is important to inform understanding of the operating flexibility that CCS plants may need to offer to the electricity network in the future among key stakeholders including policy makers and market players.

This paper uses an advanced electricity system dispatch model with hourly temporal resolution to explore Great Britain (GB) as a case study. VRE is assumed to be provided by wind power, which is expected to deliver the dominant share of VRE in the short-to-medium term in GB [8,9]. A historic high-resolution wind speed reanalysis dataset is employed and the proposed locations of future wind farms are used to produce plausible and internally consistent wind capacity deployment scenarios, highlighting the impacts of wind generation. A dynamic thermal unit commitment model is developed and coupled with a Monte Carlo based energy storage optimization model to simulate the least-cost dispatch of an assumed thermal-energy storage generation portfolio with CCS. The operation of multiple large-scale energy storage units is also investigated and the non-linear interactions with flexible CO_2 capture and other energy vectors are highlighted. Overall, the economic dispatch scheduling tool highlights the impacts of increased wind generation on the operation of the thermal fleet, energy storage, and CO_2 capture flexibility.

Nomenclature

CCGT	combined cycle gas turbine
CCS	CO_2 capture and storage
GB	Great Britain
OCGT	open cycle gas turbine
O&M	operation and maintenance
PCC	post-combustion capture
VRE	weather-variable renewable energy sources

2. Methodology

2.1. Electricity system dispatch model

A dynamic thermal unit commitment model run in MATLAB is employed to optimize the least-cost dispatch of thermal units to meet residual electricity demand (demand net of wind and energy storage output), subject to operational and system constraints over an optimization time horizon. Given thermal unit operating parameters (minimum stable generation limits, maximum export limits, minimum up/down times, up/down ramp rates, and cold/warm/hot start-up times), synchronized units must provide sufficient upward/downward spinning reserve contributions to meet demand and wind forecast error. The effect of ramp rates, start-up times, and part-load inefficiencies on the operating regimes, variable costs, and emissions of the CCS units can be investigated.

This economic dispatch unit commitment model minimizes variable production costs (fuel costs, CO_2 costs, and O&M costs that are represented by quadratic production cost functions), time-dependent exponential start-up costs, and shut-down costs across the thermal fleet. Thermal unit operating parameters, production cost functions, cold/warm/hot start-up costs, fuel input to minimum stable generation, CO_2 emission characteristics, and CO_2 capture and compression costs, are obtained from several sources [10,11,12,13,14,15].

2.2. Objective function

The objective function is expressed as:

$$\min \sum_{t=1}^{T} \sum_{g=1}^{G} \left(q_g^a + q_g^b \times P_{g,t} + q_g^c \times P_{g,t}^2 \right) + \left(C_{g,t}^{start} + C_{g,t}^{shut} \right) \quad \forall g,t \tag{1}$$

where q_g^a, q_g^b, and q_g^c are quadratic cost coefficients, $C_{g,t}^{start}$ are start-up costs (£), $C_{g,t}^{shut}$ are shut-down costs (£), and $P_{g,t}$ is the real power output of generator g at time t. Quadratic cost curves represent the fuel costs, CO_2 costs, and O&M costs of thermal generators.

Thermal units are dispatched in terms of average full load costs (£/MWh_e) either via priority list or complete enumeration. Feasible generation states are identified, and the optimal generation level and start-up/shut-down dispatch schedule is found. It is assumed that quadratic production cost functions are non-decreasing, non-negative, continuous, and convex. For the purpose of this study, non-convexities such as prohibited operation zones or valve point effects are not considered because of longer simulation times and modeling complexities.

2.3. Start-ups and shut-downs

Time-dependent exponential start-up cost functions represent the fuel consumption, and therefore CO_2 emissions, required to reassume operating temperatures after a shut-down or period of cooling. The time-dependent start-up costs for power plants equipped with and without CCS are expressed mathematically as:

$$C_{g,t}^{start} = C_g^{start,fixed} + \left(C_g^{start,cold} + e_g^{start,cold} \times C^{carbon} \times \left(1 - c_{g,t}\right) \right) \times \left(1 - e^{X_{g,t}/\tau_g^c}\right) \quad \forall g,t \tag{2}$$

where $C_g^{start,fixed}$ is the fixed start-up cost (£), $C_g^{start,cold}$ is the fuel cost required to reach minimum stable generation (£), $e_g^{start,cold}$ is the CO_2 emissions released during start-up to minimum stable generation (tCO_2), C^{carbon} is the CO_2 cost (£/tCO_2), $c_{g,t}$ is the capture rate during start-up (%), $X_{g,t}$ is number of hours generator g has been in operation (h) at time t (i.e. if generator g has been in operation for 8 hours at time t then $X_{g,t} = +8$), and τ_g^c is the thermal cooling time constant (h). The shut-down costs are assumed to be fixed $C_{g,t}^{shut} = C_g^{shut,fixed}$. A binary decision variable $s_{g,t}^b$ describes the state of each base generator unit (0 = off, 1 = on). If $s_{g,t}^b - s_{g,t-1}^b > 0$, a start-up has occurred. If $s_{g,t}^b - s_{g,t-1}^b < 0$, a shut-down has occurred. $s_{g,t}^c$ describes the state of the CO_2 capture and compression equipment (0 = off, 1 = on). When $s_{g,t}^c = 0$ and $s_{g,t} = 1$, CO_2 capture and compression systems are bypassed.

2.4. Equality and inequality constraints

The objective function is minimized subject to a number of system and operational constraints, which are presented here.

Demand constraint:

$$\sum_{g=1}^{G} P_{g,t} \times s_{g,t}^{b} = D_t - W_t - S_t \quad \forall g,t \tag{3}$$

where D_t is the electricity demand, W_t is the total available wind output (onshore + offshore), and S_t is the energy storage output.

Spinning reserve constraints:

$$\sum_{g=1}^{G} P_{g,t}^{max} \times s_{g,t}^{b} \geq D_t - W_t - S_t + K_t^{up}\,; \quad \sum_{g=1}^{G} P_{g,t}^{min} \times s_{g,t}^{b} \leq D_t - W_t - S_t - K_t^{down} \quad \forall g,t \tag{4}$$

where K_t^{up} and K_t^{down} are the upwards/downwards spinning reserve requirements (MW_e) of the system at time t.

Generator power output constraints:

$$P_{g,t}^{min} \leq P_{g,t} \leq P_{g,t}^{max}\,; \quad P_{g,t}^{min} \geq 0 \quad \forall g,t \tag{5}$$

where $P_{g,t}^{min}$ is the minimum stable generation (MW_e) and $P_{g,t}^{max}$ is the maximum export limit (MW_e) at time t.

Ramping constraints:

$$P_{g,t} \leq P_{g,t-1} + R_g^{up}\,; \quad P_{g,t} \geq P_{g,t-1} - R_g^{down} \quad \forall g,t \tag{6}$$

where R_g^{up} and R_g^{down} are the up/down ramp rates (MW_e/h).

Minimum up/down time constraints:

$$\left(X_{g,t-1} - UT_g^{min}\right) \times \left(s_{g,t-1}^{b} - s_{g,t}^{b}\right) \geq 0\,; \quad \left(-X_{g,t-1} - DT_g^{min}\right) \times \left(s_{g,t}^{b} - s_{g,t-1}^{b}\right) \geq 0 \quad \forall g,t \tag{7}$$

where UT_g^{min} and DT_g^{min} are the minimum up/down times (h).

2.5. Energy storage model

The marginal price of electricity, representing the short-run marginal costs only (fuel, CO_2, and O&M costs), is simulated for each hourly time step and used to maximize the revenue of each energy storage unit over the optimization time horizon. A Monte Carlo based optimization algorithm, adapted from [16], is utilized to simulate the operating profiles of four large-scale energy storage devices, which are representative of the existing energy storage capacity in GB. A summary of the energy storage units and their technical parameters are shown in Table 1. As a first approximation, energy storage is assumed to have negligible operating costs and start-up times. For each energy storage unit s, the time-dependent round-trip efficiency is:

$$\eta_s^{rt} = \eta_s^{c} \times \eta_s^{d} \times e^{(t_1 - t_2 / \tau_s^{e})} \tag{8}$$

where η_s^{c} and η_s^{d} are the charging and discharging efficiencies (%), and τ_s^{e} is the time-dependent 'self-discharge' efficiency (% loss per hour), between time periods t_1 and t_2 $(\Delta t = t_1 - t_2)$. The power input $\Delta P_{s,1}$ to energy storage unit s at t_1, after round-trip losses η_s^{rt}, gives the power output at t_2:

$$\Delta P_{s,2} = \Delta P_{s,1} \times \eta_s^{rt}(\Delta t) = \Delta P_{s,1} \times \eta_s^{c} \times \eta_s^{d} \times e^{(t_1 - t_2 / \tau_s^{e})} \tag{9}$$

The power input(-)/output(+) to/from each storage unit must also satisfy the inequality $P_{s,t}^{c} \leq P_{s,t} \leq P_{s,t}^{d}$ where $P_{s,t}^{c}$ is the maximum charging capacity (MW_e), and $P_{s,t}^{d}$ is the maximum discharging capacity (MW_e) at time t. Additionally, the total energy stored in the storage volume must be less than or equal to the maximum storage volume $P_s^{\max}$ (MWh_e).

Table 1. Energy storage device parameters. The time-dependent 'self-discharge' efficiency τ_s^e (% loss per hour) for all storage devices is $\tau_s^e = \infty$.

	Round-trip efficiency η_s^{rt}	Charging/discharging capacity $P_{s,t}^c = P_{s,t}^d$ (MW_e)	Energy storage volume P_s^{max} (MWh_e)
s_1	0.80	1800	9100
s_2	0.80	300	6300
s_3	0.80	400	10000
s_4	0.80	360	1300
		2860	26700

2.6. Generation portfolio

In order to highlight the changes that may impact the operation of future CCS power plants, two scenarios were characterized for the Great Britain (GB) case study considered in this paper. The first scenario consists of 15.0 GW of distributed wind capacity across GB, with 10.8 GW onshore and 4.2 GW offshore. The second scenario consists of 30.0 GW of wind capacity, but now with 15.4 GW onshore and 14.6 GW offshore. The remainder of the illustrative generation portfolio considered in these cases studies is consistent across scenarios. It comprises 4 Nuclear 3300 MW_e, 4 CCGT+PCC 1560 MW_e, 15 CCGT 1800 (2×900) MW_e, and 10 OCGT 2260 (4×565) MW_e power plant. Fossil fuel prices are taken from the central projections in [17].

The 'CCGT+PCC' plants are 1800 MW_e CCGT plants that are fitted with post-combustion CO_2 capture (PCC) and compression equipment that reduces the net electrical output of the CCGT+PCC plants to 1560 MW_e, with a maximum capture rate of $c_{g,t} = 0.9$. It is assumed that these plants use 0.27 MWh_e/tCO_2 to remove CO_2 from the flue gas, based on the performance reported in [10,11], see Table 2. Post-combustion CO_2 capture with amine scrubbing is chosen as an illustrative example because of its relative maturity and suitability for retrofit. CCGT+PCC units have additional variable O&M costs for the CO_2 capture, compression, and transportation systems. In this study it is assumed that the compression, transportation, and injection infrastructure downstream of the CO_2 capture units have the ability and capability of managing reduced and transient flows of CO_2, for indeterminate and irregular periods of time, and also that the power plants are able to provide effective CO_2 capture across a broad operating range with negligible changes to the electricity output penalty. These simplifications are made so that this study can explore 'worst case' operating patterns for future CCS power plants. However, it should be noted that CCS systems deployed in the future may not be able to offer this degree of flexibility. Therefore, further work is needed to fully understand how designers and operators of power plants with CO_2 capture may respond to the potential envelope of operating patterns and the frequency and duration of interruptions that are suggested by this study.

Table 2. Techno-economic parameters of generation portfolio (based on [10,11]).

Technology	Net thermal efficiency at full-load (MWh_e /MWh_{th})	Number of units	Capacity (MW_e)
Nuclear	0.33	4	3300
CCGT+PCC (max 90% capture rate)	0.52-0.48	4	1560-1800 (2×900)
CCGT	0.60-0.55	15	1800 (2×900)
OCGT	0.39-0.37	10	2260 (4×565)

Although the study does not attempt to fully represent flexible operation of CO_2 capture plants, the model does include the option of bypassing the CO_2 capture units during periods of high electricity price and/or low CO_2 price. For the illustrative cases reported in this paper, the CO_2 price was set at £25/tCO_2 which causes CCGT+PCC units to have slightly lower short-run marginal costs than CCGT units, as would be expected in a situation where an effective support framework for CCS has been implemented. Although there are several different approaches being explored to incentivize CCS, this use of CO_2 price could represent a 'shadow price' that broadly represents the outcome of an incentive that is not based directly on a CO_2 price. It should be noted that CO_2 emissions are quantified for all unabated and CO_2 capture equipped thermal plants during start-up, full-load and part-load operation, and shut-down to understand the CO_2 mitigation potential of CCS power plants in various scenarios and also the impact of any decisions to bypass at CO_2 capture equipped thermal plants. Finally, where necessary, generators are curtailed in order of the assumed generation constraint price [18], which is the bid price paid in £/MWh_e to reduce generation. This means that onshore wind is first curtailed when spinning reserve constraints are violated because it is assumed that for onshore wind the bid price is -£50/MWh_e and offshore wind is -£100/MWh_e.

3. Input data

A high-resolution wind speed reanalysis dataset is introduced and weather-corrected electricity demand data is utilized to simulate demand and wind generation data at consistent temporal frequency for generation portfolio analysis.

3.1. Wind data

The large-scale deployment and integration of variable-output wind power into electricity systems will create fundamental changes to residual thermal power plant operating patterns. It is therefore important to develop a sophisticated understanding of the characteristics of the wind resource. One approach to developing this understanding is to employ high-resolution atmospheric models. In this study, a historical high-resolution wind speed reanalysis dataset, created at the Institute for Energy Systems in the School of Engineering at the University of Edinburgh [19], is employed to simulate hourly wind output for wind sites in Great Britain (GB) to study the impacts of wind variability on power plant operation with CCS. The wind speed reanalysis dataset was compiled using a Weather Research and Forecasting (WRF) modelling system, which is a fully-compressible non-hydrostatic mesoscale model that uses a pressure based, terrain-following coordinate system [20]. The WRF model interpolates and integrates both static data (topography and land-use) and dynamic data (pressure, temperature, and other meteorological data) to output hourly wind speeds at 3 km resolution at three vertical levels (10 m, 80 m, and 100 m). The vertical resolution was increased close to the surface to reduce interpolation errors from the transformation of wind speeds to hub-height [20]. Wind observations from meteorological stations, anemometers, wind farm masts, buoys, lightships, oil platforms, radar profilers, and satellites, were used to configure and verify the WRF model outputs [19].

337 onshore and 49 offshore wind projects greater than 50 MW, that are either in operation, consented, in planning, or in scoping, were identified [21], see Fig. 1. For each of these locations, historic hourly wind speeds and directionality are available between January 2000 and December 2010 corresponding to 148.9 million data points, 96432 h × 386 winds sites × 4 (3 vertical levels + 1 wind directionality). However, the years 2000 and 2001 are not used because reliable electricity demand data was not available for the same time period at the time of study. Hourly winds speeds at hub-height (onshore 80 m, offshore 100 m) are transformed into ideal capacity factors using aggregate power curves [22], see Fig. 2. Ideal capacity factors are then adjusted so that they take into account long-term technical availability, and electrical and operating efficiencies. The long-term observed technical availability of wind turbines in GB is reported to be 98% for onshore and 80% for early offshore wind turbines, respectively [23,24]. Both access for maintenance and preventative/predictive maintenance are likely to improve offshore wind turbine reliability in the future. However, to ensure consistency across scenarios, a technical availability of 80% was assumed for offshore wind sites in this work. The high-resolution wind speed reanalysis dataset has already been extensively validated [19] so no further validation will be presented here.

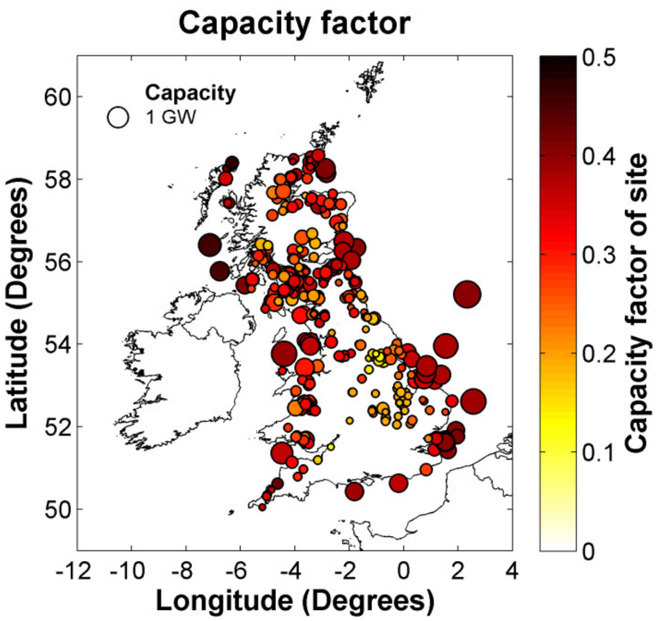

Fig. 1. The location, capacity factor, and size of 337 onshore and 49 offshore wind projects >50 MW in Great Britain that are either in operation, consented, in planning, or in scoping. The radius of each data point is proportional to the logarithm of the rated capacity for that site.

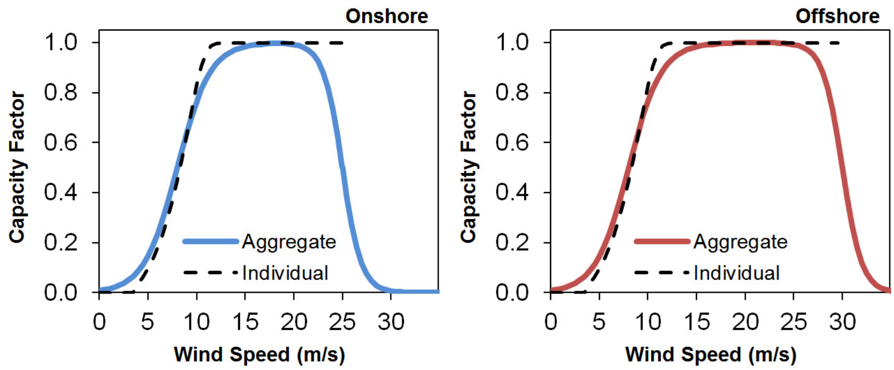

Fig. 2. Illustrative examples of aggregate power curves for large onshore and offshore wind farms and the individual power curves for onshore and offshore wind turbines. Aggregate power curves represent the spread of wind speeds experienced across wind farms.

Wind capacity deployment scenarios for GB are characterized and assimilated from several key government, industry, and engineering consultancy sources [8,21,25]. The characterization of wind deployment scenarios is internally consistent, illustrating the feasible pathways of wind expansion between 15 GW and 30 GW in GB. The power outputs of individual wind sites are aggregated to give hourly time-series' of GB wind generation for each wind capacity deployment scenario, and employed in the electricity system dispatch model to assess the operating patterns of CCS power plants under different wind conditions.

3.2. Electricity demand data

The ‘residual demand’ to be met by the thermal generation fleet is determined by subtracting hourly wind generation data (for a given historical year, but with either 15GW or 30GW capacity installed, using the scenarios outlined above) from weather-corrected electricity demand. Metered half-hourly electricity demand input data from [26] between January 2002 and December 2010 is reduced in temporal frequency to create an hourly electricity demand time-series for consistency with the wind generation data. Consistent electricity demand and wind generation input data is used for the same time period to ensure that the complex and non-linear relationship between weather patterns and electricity demand are upheld. As winter peak demand varies between years because of changing economic and cold winter weather conditions, an adjustment process normalizes winter peak demand around 60 GW over the time period. Average Cold Spell Winter Peak electricity demand data from [26] is used to construct the weather-corrected electricity demand time-series’. This maintains the short-term dynamic interactions between weather effects and electricity demand, while allowing intercomparison between scenarios based on the weather for different years.

4. Results

4.1. Operating patterns

The GB electricity system highlights the potential operating regimes and flexibility requirements of future CCS systems. Fig. 3 shows an illustrative generation dispatch pattern for the weather experienced in the first two weeks in January 2008. In this example, 30 GW of wind generation displaces large amounts of dispatchable CCGT units and creates many arbitrage opportunities for energy storage devices, which just have to cover round-trip losses in order to operate. With the assumptions used in this study, energy storage is more attractive than capture plant bypass and there is just one event (between 250 and 260 hours) where the CO_2 capture and compression units are bypassed. This occurs when the marginal price of electricity is at its highest. As expected, energy storage units at this time are also discharging, complementing the additional power output from the flexible CCGT+PCC units, and therefore reducing OCGT output. In the model, energy storage has the effect of slightly reducing the marginal price of electricity when discharging as it decreases the residual demand to be met by thermal price-setting generation assets. Bypassing the CO_2 capture unit, and exporting more electricity, is only required when electricity prices exceed a level where it is profitable to vent and pay for the additional variable operating costs associated from the extra CO_2 emitted. The competing incentives of flexible CO_2 capture and energy storage systems should be further analyzed, in particular at times of peak electricity demand, as it is not well understood how they will interact in advanced power systems.

During periods of high net wind output and low demand, there would be insufficient thermal units synchronized capable of meeting spinning reserve requirements if all the available wind generation were to be allowed to export electricity to the system. This can be seen by the areas marked as surplus in Fig. 3, where it is assumed that onshore wind is curtailed before offshore wind due to the electricity market principles currently applied in GB. In the system shown here it is, however, often possible for wind power that cannot be used to meet instantaneous demand to instead be utilized by energy storage assets. Additionally, CCGT+PCC units reduce their outputs and operate at part-load in order to accommodate more variable-output wind generation and provide sufficient upward spinning reserve. It is assumed that increasing amounts of wind generation will require increasing amounts of operating reserve due to forecasting errors and this needs to be carefully considered by electricity network operators. In this study, nuclear power plants are assumed to be inflexible, either because of technical constraints or financial motives, operating at baseload, and therefore increasing the flexibility requirements of residual thermal units. These effects cause CCGT+PCC units to operate at part-load more frequently, reducing downstream CO_2 flowrates for irregular periods of time. The duration and frequency of these CO_2 flowrate changes should be investigated further across a broader range of generation portfolios and operating environments.

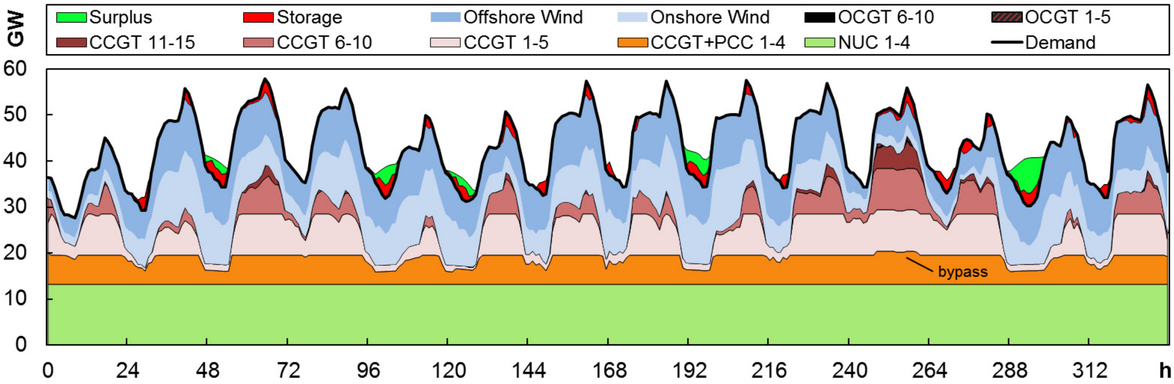

Fig. 3. Illustrative generation dispatch pattern with January 2008 weather and demand data. Generation portfolio consists of wind 30 GW; 4 energy storage devices ($\eta^{rt} = 0.8$) ; 4 Nuclear 3300 MW$_e$; 4 CCGT+PCC 1560 MW$_e$ (90% capture rate); 15 CCGT 1800 (2×900) MW$_e$; and 10 OCGT 2260 (4×565) MW$_e$.

4.2. Start-up and shut-down schedules

As outlined above, as wind provides an increasing proportion of demand, flexibility requirements for thermal power plants increase, affecting commitment decisions and start-up schedules. Fig. 4a and Fig. 5a illustrate the start-up requirements of the thermal fleet for GB weather observed from 2002-2010, assuming that no electricity storage is used. It is not yet clear what impact electricity storage will have on thermal plant operating patterns, but it is possible that introducing storage will decrease the number of start-ups/shut-downs for at least some baseload thermal plant in scenarios with large amounts of wind [27].

The data is presented as a ‘heat map’ with contours indicating a constant number of start-ups required for thermal plants by merit-order position and the time since last shut-down to meet demand in an illustrative system with 30 GW of wind capacity. For the assumptions used in this study (e.g. number of CCS power plants and costs that determine merit order position), the start-up requirements of CCS power plants are unaffected by increased wind capacity, see Table 3. This is because the CCS power plants provide spinning reserve and the model, therefore, curtails onshore wind generation when CCS units are at minimum stable generation. This has the useful outcome of ensuring a minimum CO_2 flowrate injected into the downstream CO_2 transportation and storage infrastructure, although further work is needed to explore the interactions between flexible operation of CCS power plants and the CO_2 transport and storage infrastructure over a broader range of operating patterns.

CCGT start-up requirements diverge as CCGTs are asymmetrically displaced by wind generation. Efficient CCGTs with lower variable operating costs perform more hot start-ups with increased wind generation, as their operation is disrupted and displaced for a short period of time. More inefficient CCGTs and OCGTs with higher variable operating costs are displaced more frequently and for longer, more irregular periods of time, significantly reducing the number of hot start-ups, consequently increasing the number of warm and cold start-ups. This may significantly impact the deployment and retrofit of mid-merit thermal power plants, as their operating patterns and start-up/shut-down schedules are perturbed by wind generation. This fundamental restructuring in start-up requirements is illustrated in Fig. 5a and Table 3, where the impacts of wind are highlighted in isolation and therefore no energy storage is included.

A periodic 8-hour overnight shut-down pattern is observed in scenarios with both 15 GW and 30 GW of wind capacity, but with 30 GW wind capacity there is an observed increase in the variation of cold/warm/hot start-ups. There is a slight reduction in the total number of start-ups for the thermal fleet with increasing wind capacity between the scenarios. Further work is, however, needed to fully understand the non-linear displacement of mid-merit plant and the start-up requirements as a result of near-zero variable cost wind generation.

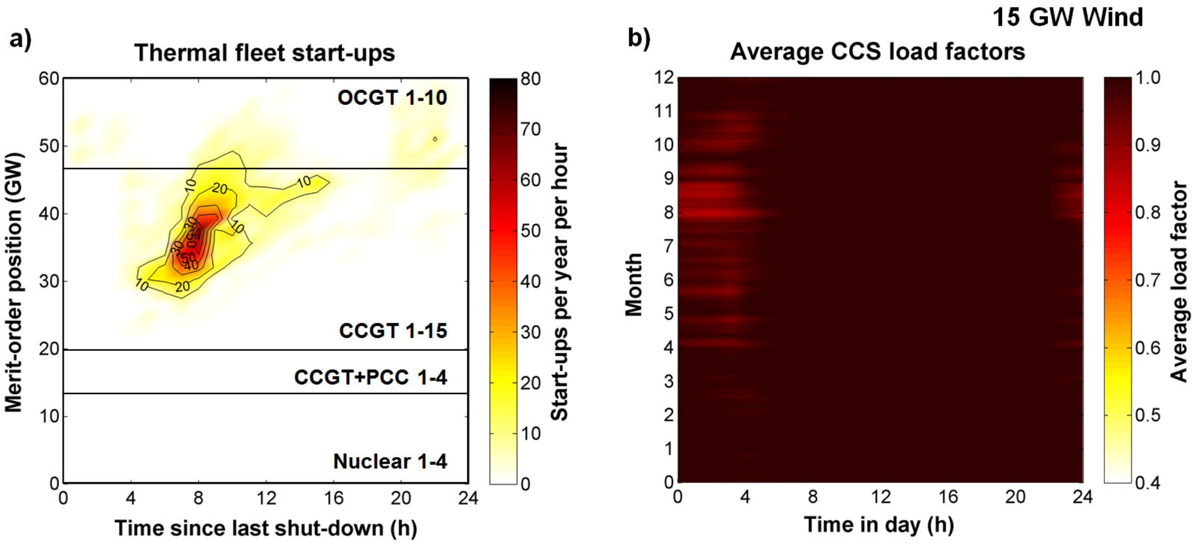

Fig. 4. (a) The average number of start-ups per year by the time since last shut-down and merit-order position; (b) the average load factors of 4 CCGT+PCC 1560 MW_e (90% capture rate) units by month and hour of day, over a 9 year period between 2002 and 2010. The illustrative generation portfolio consists of 15 GW of wind capacity; 4 Nuclear 3300 MW_e; 4 CCGT+PCC 1560 MW_e (90% capture rate); 15 CCGT 1800 (2×900) MW_e; and 10 OCGT 2260 (4×565) MW_e. The impacts of wind on start-ups are considered in isolation therefore no energy storage is included.

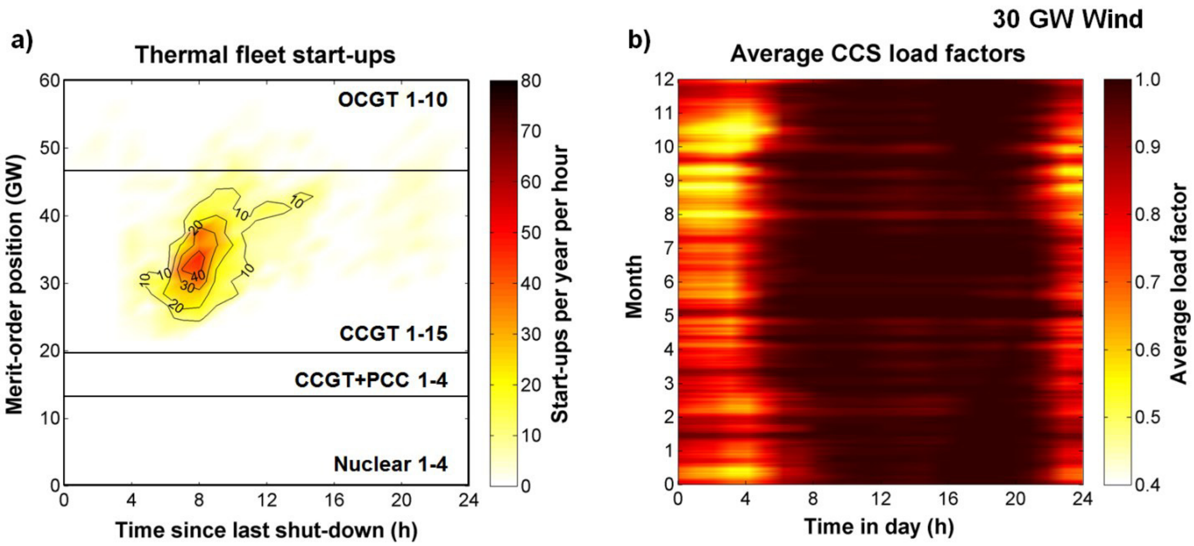

Fig. 5. (a) The average number of start-ups per year by the time since last shut-down and merit-order position; (b) the average load factors of 4 CCGT+PCC 1560 MW_e (90% capture rate) units by month and hour of day, over a 9 year period between 2002 and 2010. The illustrative generation portfolio consists of 30 GW of wind capacity; 4 Nuclear 3300 MW_e; 4 CCGT+PCC 1560 MW_e (90% capture rate); 15 CCGT 1800 (2×900) MW_e; and 10 OCGT 2260 (4×565) MW_e. The impacts of wind on start-ups are considered in isolation therefore no energy storage is included.

Table 3. The average number of hot, warm, and cold start-ups by plant type in illustrative scenarios with 15 GW and 30 GW of wind capacity over a 9 year period (2002 to 2010). Generation portfolio consists of 4 Nuclear 3300 MW_e; 4 CCGT+PCC 1560 MW_e (90% capture rate); 15 CCGT 1800 (2×900) MW_e; and 10 OCGT 2260 (4×565) MW_e.

Technology	Hot start-ups ($t \leq 8$ h)		Warm start-ups ($8 < t \leq 72$ h)		Cold start-ups ($t > 72$ h)		Total start-ups	
Wind	15 GW	30 GW	15 GW	30 GW	15 GW	30 GW	15 GW	30 GW
OCGT 6-10	0.0	0.0	0.8	0.2	0.8	0.6	1.6	0.8
OCGT 1-5	8.0	3.6	41.4	17.8	4.4	5.4	53.8	26.8
CCGT 11-15	38.2	18.6	116.0	89.0	5.8	12.2	160.0	119.8
CCGT 6-10	106.2	85.0	43.8	87.4	0.2	1.8	150.2	174.2
CCGT 1-5	11.8	40.8	1.0	12.6	0.0	0.0	12.8	53.4
CCGT+PCC 1-4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Nuclear 1-4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Fig. 4b and Fig. 5b show the seasonal and diurnal variations in average CCS load factors and the dramatic change that occurs with an increase in installed wind capacity from 15 GW to 30 GW. CCS power plants part-load and reduce output overnight, particularly in winter months when wind output is generally higher, and maintain full-output during peak hours in the evening. Even in summer there is still a significant reduction in average CCS load factors. This diurnal and seasonal variation in CCS load factors may cause significant problems when designing and operating dynamic multi-source-to-sink CO_2 networks. Therefore, careful consideration is required to determine the best approaches for development of robust and resilient CCS systems.

5. Conclusions

An advanced electricity system dispatch model is introduced and employed to simulate the least-cost dispatch schedules to meet demand after wind and energy storage output. A Monte Carlo based energy storage optimization algorithm simulates the optimal dispatch of four energy storage units with perfect foresight. This temporally explicit analysis of thermal-energy storage electricity system dispatch illustrates the operating regimes of thermal power plants. Non-linear interactions between flexible CCS power plants and other energy vectors are demonstrated for an illustrative case study example in Great Britain. For the assumptions used in this study, there is potential for infrequent use of CO_2 capture plant bypass in response to very high electricity prices (assuming a reasonable incentive for CO_2 capture plant operation with 'typical' electricity market conditions).

As an increasing proportion of the thermal fleet uses CO_2 capture it is more likely that power plants installed with CCS will have their operating patterns impacted by VRE, increasing the operational flexibility requirements. This paper has demonstrated a method that can be used to explore the potential frequency and duration of such interruptions. Further analysis is required to consider how implied changes in CO_2 flow might be accommodated in future CO_2 networks. In particular, variable intra-day wind generation displaces thermal power plants. These thermal plants then tend to minimize non-profitable operation by either part-loading or shutting down. Non-convexities such as hot/warm/cold start-ups are distinguished by utilizing representative time-dependent exponential start-up functions, which simulate the costs and CO_2 emissions required to increase and reassume operating temperatures by burning fuel after a shut-down. An increased variation in the number of hot/warm/cold start-ups for mid-merit plants is observed with increased wind capacity, which emphasizes the importance of using time-dependent start-up costs in wind-based unit commitment studies. The impacts of wind generation are isolated to study the operating patterns and flexibility implications for CCS units.

Further work should explore the competing interactions between flexible CO_2 capture and energy storage, the potential duration and frequency of CO_2 flowrate disruptions, the flexibility requirements of future CCS systems, and the asymmetric and non-linear displacement of mid-merit plants, in addition to their contribution to overall system flexibility across a wide range of generation portfolios and operating environments. This will be important for the design, operation, regulation, and financing of future dynamic multi-source-to-sink CO_2 networks.

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